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TITLE

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MULTI-PART PLUNGER

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CROSS REFERENCE APPLICATIONS

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This application is a non-provisional application

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claiming the benefits of provisional application no.

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60/456,667 filed March 18, 2003.

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FIELD OF THE INVENTION

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The present invention relates to an improved plunger lift apparatus for the lifting of formation liquids in a hydrocarbon well. More specifically the improved plunger consists of a two piece apparatus that operates to increase the well efficiency, insure positive mechanical connection during lift, and separate at the top of the well.

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BACKGROUND OF THE INVENTION

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A plunger lift is an apparatus that is used to increase the productivity of oil and gas wells. In the early stages of a well's life, liquid loading is usually not a problem. When rates are high, the well liquids are carried out of the tubing by the high velocity gas. As the well declines, a critical velocity is reached below which the heavier liquids

1 do not make it to the surface and start to fall back to the
2 bottom exerting back pressure on the formation, thus loading
3 up the well. A plunger system is a method of unloading gas
4 in high ratio oil wells without interrupting production. In
5 operation, the plunger travels to the bottom of the well
6 where the loading fluid is picked up by the plunger and is
7 brought to the surface removing all liquids in the tubing.
8 The plunger also keeps the tubing free of paraffin, salt or
9 scale build-up. A plunger lift system works by cycling a
10 well open and closed. During the open time a plunger
11 interfaces between a liquid slug and gas. The gas below the
12 plunger will push the plunger and liquid to the surface.
13 This removal of the liquid from the tubing bore allows an
14 additional volume of gas to flow from a producing well. A
15 plunger lift requires sufficient gas presence within the
16 well to be functional in driving the system. Oil wells
17 making no gas are thus not plunger lift candidates.

18 As the flow rate and pressures decline in a well,
19 lifting efficiency declines geometrically. Before long the
20 well begins to "load up". This is a condition whereby the
21 gas being produced by the formation can no longer carry the
22 liquid being produced to the surface. There are two reasons
23 this occurs. First, as liquid comes in contact with the wall
24 of the production string of tubing, friction occurs. The

1 velocity of the liquid is slowed and some of the liquid
2 adheres to the tubing wall, creating a film of liquid on the
3 tubing wall. This liquid does not reach the surface.
4 Secondly, as the flow velocity continues to slow the gas
5 phase can no longer support liquid in either slug form or
6 droplet form. This liquid along with the liquid film on the
7 sides of the tubing begin to fall back to the bottom of the
8 well. In a very aggravated situation there will be liquid in
9 the bottom of the well with only a small amount of gas being
10 produced at the surface. The produced gas must bubble
11 through the liquid at the bottom of the well and then flow
12 to the surface. Because of the low velocity very little
13 liquid, if any, is carried to the surface by the gas. Thus,
14 as explained previously, a plunger lift will act to remove
15 the accumulated liquid.

16 A typical installation plunger lift system 100 can be
17 seen in Fig. 1. Lubricator assembly 10 is one of the most
18 important components of plunger system 100. Lubricator
19 assembly 10 includes cap 1, integral top bumper spring 2,
20 striking pad 3, and extracting rod 4. Extracting rod 4 may
21 or may not be employed depending on the plunger type. Below
22 lubricator 10 is plunger auto catching device 5 and plunger
23 sensing device 6. Sensing device 6 sends a signal to surface
24 controller 15 upon united plunger mechanism (UPM) 200
25 arrival at the well top. UPM 200 is shown to represent the

1 plunger of the present invention and will be described below
2 in more detail. Sensing the plunger is used as a programming
3 input to achieve the desired well production, flow times and
4 wellhead operating pressures. Master valve 7 should be sized
5 correctly for the tubing 9 and UPM 200. An incorrectly sized
6 master valve will not allow UPM 200 to pass. Master valve 7
7 should incorporate a full bore opening equal to the tubing 9
8 size. An oversized valve will allow gas to bypass the
9 plunger causing it to stall in the valve. If the plunger is
10 to be used in a well with relatively high formation
11 pressures, care must be taken to balance tubing 9 size with
12 the casing 8 size. The bottom of a well is typically
13 equipped with a seating nipple/tubing stop 12. Spring
14 standing valve/bottom hole bumper assembly 11 is located
15 near the tubing bottom. The bumper spring is located above
16 the standing valve and can be manufactured as an integral
17 part of the standing valve or as a separate component of the
18 plunger system.

19 Surface control equipment usually consists of motor
20 valve(s) 14, sensors 6, pressure recorders 16, etc., and an
21 electronic controller 15 which opens and closes the well at
22 the surface. Well flow 'F' proceeds downstream when surface
23 controller 15 opens well head flow valves. Controllers
24 operate on time, or pressure, to open or close the surface

1 valves based on operator-determined requirements for
2 production. Modern electronic controllers incorporate
3 features that are user friendly, easy to program, addressing
4 the shortcomings of mechanical controllers and early
5 electronic controllers. Additional features include: battery
6 life extension through solar panel recharging, computer
7 memory program retention in the event of battery failure and
8 built-in lightning protection. For complex operating
9 conditions, controllers can be purchased that have multiple
10 valve capability to fully automate the production process.

11 Modern plungers are designed with various sidewall
12 geometries and can be generally described as follows:

13 A. Shifting ring plungers for continuous contact
14 against the tubing to produce an effective
15 seal with wiping action to ensure that all
16 scale, salt or paraffin is removed from the
17 tubing wall. Some designs have by-pass valves
18 to permit fluid to flow through during the
19 return trip to the bumper spring with the by-
20 pass shutting when the plunger reaches the
21 bottom. The by-pass feature optimizes plunger
22 travel time in high liquid wells

- 1 B. Pad plungers with spring-loaded interlocking
2 pads in one or more sections. The pads expand
3 and contract to compensate for any
4 irregularities in the tubing thus creating a
5 tight friction seal. Pad plungers can also
6 have a by-pass valve as described above.
- 7 C. Brush plungers incorporate a spiral-wound,
8 flexible nylon brush section to create a seal
9 and allow the plunger to travel despite the
10 presence of sand, coal fines, tubing
11 irregularities, etc. By-pass valves may also
12 be incorporated.
- 13 D. Solid plungers with solid sidewall rings for
14 durability. Solid sidewall rings can be made
15 of various materials such as steel, poly
16 materials, Teflon, stainless steel, etc. Once
17 again, by-pass valves can be incorporated.
- 18 E. Snake plungers, which are flexible for coiled
19 tubing and directional holes, and can be used
20 as well in straight standard tubing.

21 Recent practices toward slim-hole wells that utilize
22 coiled tubing lend also themselves to plunger systems.

1 Because of the small tubing diameters, a relatively small
2 amount of liquid may cause a well to load-up or a relatively
3 small amount of paraffin may plug the tubing.

4 Plungers use the volume of gas stored in the casing and
5 the formation during the shut-in time to push the liquid
6 load and plunger to surface when the motor valve opens the
7 well to the sales line or to the atmosphere. To operate a
8 plunger installation, only the pressure and gas volume in
9 the tubing/casing annulus is usually considered as the
10 source of energy for bringing the liquid load and plunger to
11 surface.

12 The major forces acting on the cross-sectional area of
13 the bottom of the plunger are:

- 14 • The pressure of the gas in the casing pushes up on the
15 liquid load and the plunger;
- 16 • The sales line operating pressure and atmospheric
17 pressure push down on the plunger
- 18 • The weight of the liquid and the plunger pushes down on
19 the plunger;

- 1 • Once the plunger begins moving to the surface, friction
2 between the tubing and the liquid load acts to oppose
3 the plunger;
- 4 • In addition, friction between the gas and tubing acts
5 to slow the expansion of the gas.

6 The major disadvantage of conventional plunger lifts is
7 that the well must be shut-in in order for the plunger to
8 fall to the bottom of the well. Two part plunger systems
9 (ball-type or other non-positive mechanical plungers) can
10 lose plunger piece to piece contact during lift due a drop
11 in critical velocity, collar banging, hitting slugs of
12 fluid, paraffin or scale particles, which decreases well
13 efficiency. If the ball falls back to the bottom, fluid is
14 then allowed to fall back to the bottom, which keeps the
15 well in a loaded state. The only thing that holds the ball
16 on the plunger is the upward flow of gas and fluid. See U.S.
17 Patent Nos. 6,209,637 and 6,467,544 to Wells. When the
18 Wells two-part piston rises, changing well conditions can
19 cause the ball to disconnect from the sleeve, resulting in
20 lost well production.

21 The present invention in its various embodiments
22 latches a lower plug to an upper sleeve, thereby preventing
23 an accidental separation. Plunger drop travel time slows or

1 limits well production. Also fishing balls out of a well is
2 a problem and sometimes requires pulling the complete tubing
3 string. Well production increases are always critical. What
4 is needed is a plunger lift apparatus that can insure a
5 positive contact during lift, drop back to the well bottom
6 quickly and easily and assist in increasing well production
7 by increasing lift cycle times. What is also needed is a
8 two-part plunger system that is retrievable from the well.
9 The apparatus of the present invention provides a solution
10 to these aforementioned deficiencies.

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15 SUMMARY OF THE INVENTION

16 The main aspect of the present invention is to provide
17 a two part plunger apparatus that will increase well
18 production levels.

19 Another aspect of the present invention is to provide a
20 two part plunger apparatus that ensures a mechanical
21 connection during the lift from the well bottom and that
22 will mechanically separate at the lift top.

1 Another aspect of the present invention is to allow
2 both the plunger top mechanism (PTM) and the plunger bottom
3 mechanism (PBM) to independently fall inside the tubing to
4 the well hole bottom with increased speed without impeding
5 well production.

6 Another aspect of the present invention is to allow for
7 current plunger sidewall geometries to be utilized in the
8 PTM.

9 Yet another aspect of the present invention is to
10 provide for a magnetic latching of the PTM and PBM during
11 lift, the preferred embodiment.

12 Another aspect of the present invention is to provide
13 for a mechanical latching of the PTM and PBM during lift, an
14 alternate embodiment.

15 Yet another aspect of the present design is to provide
16 a design that has an inherent flow by-pass when falling,
17 thus eliminating any need for a by-pass valve.

18 Other aspects of this invention will appear from the
19 following description and appended claims, reference being
20 made to the accompanying drawings forming a part of this
21 specification wherein like reference characters designate
22 corresponding parts in the several views.

1 The present invention comprises a plunger lift
2 consisting of two separate parts that will latch together at
3 the well bottom thus creating a united plunger mechanism
4 (UPM) acting to carry fluids from the bottom of the well to
5 the surface. The latching is a magnetic latching in the
6 preferred embodiment. The latching can also be a mechanical
7 latching in alternate embodiments. The UPM latching is
8 deactivated at the top of the well by a rod or other de-
9 latching device, thereby separating the UPM into the PTM and
10 PBM. The PTM is auto-caught and held in the lubricator at
11 the top surface while the PBM is allowed to separately fall
12 back into the well.

13 The PTM will be dropped back into the well when well
14 conditions are met with liquid loading. The PTM will re-
15 latch to the PBM when it returns to the well bottom to form
16 a solid two-piece plunger, the UPM.

17 The preferred embodiment of the present invention
18 employs a fairly strong permanent magnet, which is encased
19 within the PBM to provide a magnetic attachment to the PTM.
20 Other embodiments of the present invention employ a
21 mechanical latch between the PTM and PBM during lift.

22 The PBM is designed to have a small outside diameter
23 (OD) than the tubing and a geometric design to allow it to

1 quickly travel to the well bottom without impeding well
2 flow. The PTM is designed with standard aforementioned
3 sidewall geometries and a hollow inside to allow it to
4 quickly travel to the well bottom once it is released by the
5 auto-catcher at the surface.

6 The present invention assures an efficient lift due to
7 the fact that both the PTM and PBM are latched to form one
8 plunger unit during lift. The present invention also
9 optimizes well efficiency due to the fact that both PTM and
10 PBM can separately and quickly travel to the well bottom.

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BRIEF DESCRIPTION OF THE DRAWINGS

16
17 Fig. 1 (prior art) is an overview depiction of a typical
18 plunger lift system installation.

19 Fig. 2 is a side view of the preferred embodiment of a UPM,
20 separated into its PTM and PBM units.

21 Fig. 2A is a cross-sectional view of the PBM unit at point
22 A-A of Fig. 2.

1 Fig. 3 is a side cross sectional view of the preferred
2 embodiment of the present invention showing the UPM,
3 shown in its magnetically latched state.

4 Figs. 4A, 4B is a blow-up cross-sectional view of the
5 preferred embodiment of the present invention showing
6 each subassembly of the UPM.

7 Fig. 5 is a side view of the PTM.

8 Fig. 6 is a side view of various side-wall geometries of the
9 PTM.

10 Fig. 7 is a side view of the UPM with magnetic latching, the
11 preferred embodiment of the present invention.

12 Fig. 8 is a side view of latch-down pickup, an alternate
13 embodiment of the present invention.

14 Fig. 8A is a blow up of the latch-down pickup area of a
15 compression ring pickup shown in Fig. 8.

16 Fig. 9 is a side view of a compression ring pickup, yet
17 another alternate embodiment of the present
18 invention.

19 Fig. 9A is a blow up of the compression ring pickup area as
20 shown in Fig. 9.

21 Fig. 10 is a side view of a spring-loaded pickup, still
22 another alternate embodiment of the present
23 invention.

24 Fig. 10A is a blow up of the spring-loaded pickup area as
25 shown in Fig. 10.

1 Fig. 11 is a horizontal cross-sectional view of Fig. 2,
2 taken along line A-A, viewed in the direction taken
3 by the arrows.
4 Fig. 12 is a horizontal cross-sectional view of Fig. 5,
5 taken along line B-B, viewed in the direction taken
6 by the arrows.
7 Fig. 13 is a side view of a spring-loaded top sleeve having
8 a ball as the sealing plunger.
9 Fig. 14 is a side view of a compression ring top sleeve
10 having a ball as the sealing plunger.
11 Fig. 15 is a side view of a latch down top sleeve having a
12 ball as the sealing plunger.
13 Fig. 16 is a side view with a partial cutaway showing
14 magnets in the top sleeve, and having a ball as the
15 sealing plunger, the ball being made of a ferrous
16 material such as stainless steel.

1 Before explaining the disclosed embodiment of the
2 present invention in detail, it is to be understood that the
3 invention is not limited in its application to the details
4 of the particular arrangement shown, since the invention is
5 capable of other embodiments. Also, the terminology used
6 herein is for the purpose of description and not of
7 limitation.

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6 7 Detailed Description of the Invention

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9 The present invention provides a plunger lift apparatus
10 that consists of two basic parts, a PTM and a PBM that are
11 latched together to form the UPM during lift. The plunger
12 lift of the present invention basically consists of the
13 following discrete steps:

- 14 1. The two piece plunger, or UPM, is at the
15 bottom of a well in a mechanically latched
16 state (magnetic or mechanical) with liquid
17 loading on top of the plunger;
- 18 2. The well is open for flow at which time the
19 UPM rises to carry liquids out of the well
20 bore.
- 21 3. The UPM separates at the top of the well into
22 its basic components, the PTM and PBM, via a
23 de-latching rod (or other means) while the PTM

1 is secured in an auto-catcher and the PBM
2 starts down the well at an increased speed
3 against the well flow without effecting well
4 operating efficiency due to its cross-
5 sectional geometry, which will be described
6 below in more detail.

7 4. The well flows for a set time or condition
8 controlled by the well-head controller.

9 5. The auto-catcher releases the PTM after a set
10 time or condition.

11 6. The PTM, with its hollowed center orifice,
12 falls against the well flow at a faster rate
13 than a standard plunger and latches to the PBM
14 at the well bottom. The orifice allows the PTM
15 to travel to the well bottom without impeding
16 well flow and also optimizes plunger travel
17 time in high liquid wells.

18 7. The well plunger lift cycle starts again.

19 The PTM and PBM that are latched together to form a
20 single UPM during lift and separate back into two discrete
21 parts (PTM and PBM) once at the well surface. The UPM acts
22 as a sealed device during lift that functions to carry
23 fluids to the well surface. The latching of the PTM and PBM

1 during lift is maintained via either magnetic or mechanical
2 latching. The preferred embodiment of the present invention
3 employs a magnetic latching design. It should be noted that
4 mechanical latching could also be employed.

5 The utilization of magnetic (or mechanical) latching
6 assures connection of the PTM and PBM during the UPM lift
7 from the well bottom. The mechanical separation of the UPM
8 into the PBM and PTM is accomplished by a rod or de-latching
9 device at the top of the well, usually contained within the
10 lubricator. Older systems employing a ball and top plunger
11 mechanism tend to separate during lift causing lift
12 restarts.

13 The PBM is geometrically designed to have a fluid/gas
14 dynamic type shape to allow it to quickly pass against the
15 flow and to the well bottom. Such designs may include, but
16 not be limited to, a torpedo shape, an anvil shape, etc. The
17 PBM is designed with outside dimensions to be sufficiently
18 smaller than the tubing inside diameter allowing it to
19 efficiently fall against the flow of the well. The PBM
20 design allows gas or liquids to continue to flow to the well
21 surface after the lift is complete and the PBM is falling
22 against the well flow. The PBM will return to the bottom
23 with an efficient speed until it comes to rest on the bottom

1 sitting or on a bumper spring. This aforementioned falling
2 action of the PBM will allow the well to continue to flow
3 and will not impact the well flow efficiency thereby
4 allowing for higher well production levels. If the
5 'difference' in cross-sectional area of the PBM and the
6 inside cross-sectional area of well tubing is equal to or
7 greater than the minimum cross-sectional area of any other
8 flow point in the well, full well flow can continue without
9 the PBM impeding maximum flow. Likewise, no well flow will
10 be impeded by the PTM if the inner orifice cross-sectional
11 area of the PTM is greater than or equal to the minimum
12 cross-sectional area of any other flow point in the well.
13 The time to fall of both the PBM and the PTM is shorter than
14 prior art allowing a time-savings in lift cycles, thus
15 adding to well efficiency. Older design, solid plungers, not
16 only required well shut-off, but also could not be released
17 to fall back to the well bottom until flow had stopped.

18 In the preferred embodiment of the present invention,
19 the PBM contains a relatively strong internal magnet. The
20 magnet is positioned in proximity below the top surface of
21 the PBM with its North and South poles facing in an axial
22 direction along the PBM. A non-magnetic material is placed
23 around the peripheral surface of the magnet (between the

1 magnet and the outside surface of the PBM) to optimize
2 magnetic flux lines to flow between the magnet's north and
3 south poles. The top surface of the PBM is designed with a
4 magnetic material and is annular in shape with a slanted
5 surface (cone type shaped) to optimize magnetic latching to
6 similar but outside annular type surface on the PTM. It
7 should be noted that other surface shapes could be employed.
8 Although the PBM of the preferred embodiment might consist
9 of separate parts; combinations of set pins, screw-type
10 designs or other mechanisms can be used to secure all
11 individual parts into a one-piece PBM to hold each of its
12 components together.

13 When the UPM is lifted to the top of the well and
14 separation occurs allowing the PBM to fall to the bottom,
15 the PTM is caught and held at the top of the well by an auto
16 catcher. The PTM is dropped back into the well when pre-
17 determined well conditions are met. The PTM will re-latch to
18 the PBM when it returns to the well bottom to form a united
19 two-piece plunger, the UPM. The PTM is designed with an
20 inside hollow orifice which allows it to quickly fall back
21 into the well, against the well flow, without impacting well
22 production. The outside surface of the PTM can be designed
23 with any of the aforementioned type geometries such as ring,

1 pad, brush, solid or snake. The inside hollow orifice design
2 permits an inherent flow by-pass when falling, thus
3 eliminating any need for a separate by-pass valve.
4 Elimination of by-pass valves as found in prior art plungers
5 increases plunger reliability and also avoids extra
6 maintenance associated with cleaning obstructed valve and/or
7 passages. The bottom of the PTM is made of a ferromagnetic
8 material to help produce the most strongly magnetic
9 attraction in latching to the PBM. The shape of the bottom
10 of the PTM is annular and with an inside conical opening at
11 the orifice to accept the shape of the outside conical
12 dimension of the PBM. When the PTM falls to the well bottom,
13 it magnetically latches to the PBM. This magnetic latching
14 assures continuous latching during lift. The shape of the
15 top of the PTM can be designed such that it allows easy
16 retrieval from the well bottom. An indented inside top
17 collar would easily allow a ball and spring mechanism on a
18 plunger retriever to fall inside the PTM orifice (under
19 spring pressure) at its top position. The top collar of the
20 PTM can be designed with a standard American Petroleum
21 Institute (API) internal fishing neck. The spring loaded
22 ball within the retriever and protruding outside its surface
23 would thus fall within the API internal fishing neck at the

1 top of the PTM orifice for a small distance to a point
2 wherein the inside diameter of the PTM orifice would
3 increase to allow the ball to spring outward. This condition
4 would allow retrieving of the entire UPM as the UPM is in
5 its latched state.

6 Alternate embodiments of the present invention can
7 utilize a mechanical latching of the PTM and PBM during
8 lift. Such embodiments might employ mechanical means such as
9 ball and spring mechanisms on one device (PTM or PBM) to
10 latch into a groove on the other device (PBM or PTM).

11 The present invention assures an efficient lift due to
12 the fact that both the PTM and PBM are latched to form one
13 plunger unit during lift. The present invention also
14 optimizes well efficiency due to the fact that both PTM and
15 PBM can separately and quickly travel to the well bottom.
16 Preliminary data indicates productivity increases ranging
17 from 120% to 200% depending on well parameters.

18 Referring now to the drawings, Fig. 2 is a side view of
19 the preferred embodiment of UPM 200 separated into both the
20 PTM 20 and PBM 21. PTM 20 is shown with a 'solid ring' 22
21 sidewall geometry. As previously described, other sidewall
22 geometries such as 'brush', 'ring', 'pad' etc. can be
23 employed in PTM 20. PTM 20 is basically an annular apparatus

1 with an inner orifice, which can be seen below in Figs. 3,
2 4A. PBM 21 is shown with an anvil-type shape to optimize
3 efficiency when dropping against the well flow, while
4 allowing the well flow to continue. PBM 21 consists of the
5 following components:

- 6 1. Liquid/gas by-pass bottom end 24 with a mandrel
7 type section with main flute 23 in a triangular
8 shape and outer flutes 17 as inverted triangular
9 shaped areas (see Fig. 2A);
- 10 2. By-pass south connector 25;
- 11 3. Magnet isolator ring 26, which is made of non-
12 magnetic (anti-ferromagnetic) material, and
13 contains the magnet (not shown). Magnet isolator
14 ring 26 can be seen externally as an annular ring
15 around the area surrounding the internal PBM
16 magnet; and
- 17 4. By-pass head 28.

18 Fig. 2A is a cross-sectional view of the PBM 21 unit
19 across point A-A of Fig. 2. The A-A cross-sectional area of
20 the liquid/gas by-pass end 21 is shown as a mandrel type
21 section with main flute 23 in a triangular shape and outer
22 flutes 17 as inverted triangular shaped areas. It should be

1 noted that although a specific geometry is shown, other
2 geometries can be easily designed (for example, anvil
3 shaped, spear shaped or other) that would allow PBM 21 to
4 easily fall against the well flow. A good design for PBM 21
5 can be obtained if the cross-sectional area for 'any' cross
6 section cut across PBM 21 has an area such that the
7 'difference' between the cross-sectional area of PBM 21 and
8 the cross-sectional area of the inner diameter of tubing 8
9 (ref. Fig. 1) is greater than the 'minimum' cross-sectional
10 area of any other flow point in the well. This will assure
11 that PBM 21 does not impede the well flow. Likewise, the
12 cross-sectional area of PTM orifice should be equal to or
13 greater than the 'minimum' cross-sectional area of any other
14 flow point in the well.

15 Fig. 3 is a side cross sectional view of the preferred
16 embodiment of a UPM 200, shown in its magnetically latched
17 state with PTM 20 magnetically latched to PBM 21. PBM 21 is
18 magnetically drawn into the bottom orifice of PTM 20 when
19 fully magnetically latched. PBM 21 is shown in the preferred
20 embodiment consisting of a plurality of sub-assembly
21 components. Liquid/gas flow by-pass end 24 is designed in
22 mandrel-type geometry to assist PTM 20 to easily fall

1 against the well flow. Other geometries (i.e., anvil, spear,
2 torpedo etc.) could also be employed. Other PBM 21
3 subassembly parts consist of subassembly bypass south
4 connector 25, magnet isolator ring 26 (anti-ferromagnetic
5 material), magnet 27, and by-pass head 28. Surface S is the
6 conical surface at which annular surfaces from PTM 20 and
7 PBM 21 are held magnetically and acts as a seal during lift.
8 Annular upper surface S3 provides a secondary seal. Magnet
9 27 is of sufficient strength to pull PBM 21 up into the
10 receiving PTM orifice 29. Magnetic flux lines M are shown
11 which permeate both sections of PTM 20 and PBM 21. PTM 20 is
12 shown with a solid ring 22 outer surface geometry. Inner cut
13 groves 30 of this geometry allow sidewall debris to
14 accumulate when PTM is rising or falling. Other outer
15 surfaces can also be employed (ref. Fig. 6). The top of PTM
16 20 is designed as an API internal fishing neck for easy
17 retrieval by a standard API internal fishing neck retrieving
18 pickup mechanism (not shown) to retrieve UPM 200 in its
19 mechanically latched form.

20 Figs. 4A, 4B is a blow up view of UPM 200 showing each
21 subassembly of PBM 21. PTM 20 is shown with a solid ring 22
22 outer surface geometry and containing inner groves 30.

1 Liquid/gas by-pass end 24 is fluid/gas dynamic in shape
2 allowing it to cut through the well flow. Shapes other than
3 that shown can also be employed. Bottom end threaded area 41
4 allows for mechanical threading connection to bypass south
5 connector 25 lower threads 43. Liquid/gas by-pass roll pin
6 hole 40 and bypass south connector roll pin hole 42 are
7 aligned for a pressed pin (not shown) positive retention
8 mechanism between liquid/gas by-pass end 24 and bypass south
9 connector 25. ~~It~~A ~~M~~magnet insulator ring 26 is attached to
10 bypass south connector 25 via screwing south connector
11 treads 44 and magnet insulator ring treads 46. The magnet
12 insulator ring 26, which is a non-magnetic element such as
13 aluminum, serves to isolate the sides of the magnet, thereby
14 radiating longitudinally the magnetic flux lines M (see Fig.
15 3) to better couple the magnet 27 to the PTM 20. Bypass
16 south connector roll pin hole 45 and magnet insulator ring
17 roll pin hole 47 are aligned for a pressed roll pin (not
18 shown) positive retention to hold both sub-assemblies into
19 position. Magnet 27 is permanently positioned and is shown
20 such that its north pole N faces upward and its south pole S
21 faces downward. It should be noted that magnet 27 could also
22 be aligned in an opposite manner to that shown, that is,

1 with its north pole N facing downward and its south pole S
2 facing upward. Surface S1 is aligned and extends to surface
3 S2 when both subassemblies are together. These form annular
4 surface S (ref. Fig. 3) of PBM 21 at which point PTM 20 and
5 PBM 21 are held together magnetically. By-pass head 28 mates
6 to magnet insulator ring 26 via by-pass head treads 49 and
7 magnet insulator treads 48. Both units are mechanically held
8 together by a roll pin (not shown) placed by aligning magnet
9 insulator roll pin hole 47 with by-pass head roll pin hole
10 50. Roll pins are inserted after alignment and retained via
11 compression or spreading of roll pin end(s). It should be
12 noted that alignment of all roll pin holes in PBM 21 could
13 be accomplished by any of the following methods:

- 14 1. Threading all PBM parts together and then
15 drilling a roll pin holes in appropriate
16 locations.
- 17 2. Pre-drilling roll pin holes and aligning holes
18 after PBM parts are threaded together.

19 It should also be noted that other means of connecting PBM
20 parts can be accomplished via use of adhesives within the
21 threads to hold parts together (i.e. no roll pins) or other
22 fastening means.

1 Fig. 5 is a side view of PTM 20 with solid rings 22
2 sidewall geometry for durability and containing inner grooves
3 30. Sidewall geometry can be made of various materials such
4 as steel, poly materials, Teflon, stainless steel, etc.
5 Cross-section B-B is described below in Fig. 12.

6 Fig. 6 is a side view of various side-wall geometries
7 of the PTM. All geometries described below have an internal
8 orifice as previously described in PTM 20. All side-wall
9 geometries described below can be found in present
10 industrial offerings. These side-wall geometries are
11 described as follows:

12 A. As previously discussed solid ring 22 sidewall
13 is shown in solid plunger PTM 20. Solid
14 sidewall rings 22 can be made of various
15 materials such as steel, poly materials,
16 Teflon, stainless steel, etc.

17 B. Shifting ring 81 sidewall geometry is shown in
18 shifting ring plunger top mechanism 80.
19 Shifting rings 81 sidewall geometry allows for
20 continuous contact against the tubing to
21 produce an effective seal with wiping action
22 to ensure that all scale, salt or paraffin is

1 removed from the tubing wall. Shifting rings
2 81 are all individually separated at each
3 upper surface and lower surface by air gap 82.

4 C. Pad plunger top mechanism 60 has spring-loaded
5 interlocking pads 61 in one or more sections.
6 Interlocking pads 61 expand and contract to
7 compensate for any irregularities in the
8 tubing thus creating a tight friction seal.

9 D. Brush plunger top mechanism 70 incorporates a
10 spiral-wound, flexible nylon brush 71 surface
11 to create a seal and allow the plunger to
12 travel despite the presence of sand, coal
13 fines, tubing irregularities, etc.

14 Fig. 7 is a side view of the UPM 200 with magnetic
15 latching, the preferred embodiment of the present invention.
16 Shown are aforementioned PTM 20 and PBM 21. It is shown
17 again for reference purposes alongside alternate
18 embodiments.

19 Fig. 8 is a side view of latch-down pickup 300, an
20 alternate embodiment of the present invention. In this
21 alternate embodiment, latch down top mechanism 310 is
22 mechanically latched to latch down bottom mechanism 302.

1 Fig. 8A is a blow up of the latch-down pickup area 303. At
2 the bottom of latch down top mechanism 310 is a set of two
3 or more female pickup fingers 304, which wrap around
4 recessed male sleeve 305. Recessed male sleeve 305 is
5 tapered down from upper neck 306 providing a recess for
6 female pickup fingers 304 to compress around recessed male
7 sleeve 305. Female pickup fingers 304 (two or more) will
8 expand in direction 307 as shown when upper neck 306 enters
9 latch down top mechanism 310 and contract when over tapered
10 down recessed male sleeve 305. Surface mating area S3
11 provide for a seal upon plunger lift. An orifice in latch
12 down top mechanism 310 is similar to PTM orifice 29 as
13 previously described. As aforementioned extracting rod 4
14 (ref. Fig. 1) separates latch down top mechanism 310 from
15 latch down bottom mechanism 302 upon lift completion at the
16 well top.

17 Fig. 9 is a side view of a compression ring pickup 400.
18 In this alternate embodiment, compression ring top mechanism
19 410 is mechanically latched to compression ring bottom
20 mechanism 402. Fig. 9A is a blow up of the compression ring
21 pickup area 403. At the bottom of compression ring top
22 mechanism 410 is recessed groove annular ring 404, which
23 allows compression ring 405 to expand, thereby allowing
24 compression ring top mechanism 410 to mechanically latch to
25 compression ring bottom mechanism 402. Compression ring 405

1 is affixed to compression ring bottom mechanism 402 and will
2 compress as compression ring bottom mechanism 402 enters
3 compression ring top mechanism 410. Compression ring 405 can
4 be made with various compressible materials such as, but not
5 limited to, rubber, nylon, steel, or other metallic or poly-
6 type materials. Surface mating area S3 provides for a seal
7 upon plunger lift. An orifice in compression ring top
8 mechanism 410 is similar to PTM orifice 29 as previously
9 described. As aforementioned extracting rod 4 (ref. Fig. 1)
10 separates compression ring top mechanism 410 from
11 compression ring bottom mechanism 402 upon lift completion
12 at the well top.

13 Fig. 10 is a side view of a spring-loaded pickup 500,
14 still another alternate embodiment of the present invention.
15 In this alternate embodiment, spring-loaded top mechanism
16 510 is mechanically latched to spring-loaded bottom
17 mechanism 502. Fig. 10A is a blow up of the spring-loaded
18 pickup area 503 as shown in Fig. 10. At the bottom of
19 spring-loaded top mechanism 510 is recessed area containing
20 spring 504 and ball 505, which sit in slot hole 507. Ball
21 505 will contract into spring 504 when spring-loaded bottom
22 mechanism 502 enters spring-loaded top mechanism 510.
23 Spring-loaded bottom mechanism 502 contains recessed annular
24 groove (bearing race) 506 which will allow ball 505 to expand
25 out from spring 504 and maintain a mechanical connection

1 between units a spring-loaded bottom mechanism 502 enters
2 into spring-loaded top mechanism 501. Surface mating area S3
3 provides for a seal upon plunger lift. An orifice in spring-
4 loaded top mechanism 501 is similar to PTM orifice 29 as
5 previously described. As aforementioned extracting rod 4
6 (ref. Fig. 1) separates spring-loaded top mechanism 501 from
7 spring-loaded bottom mechanism 502 upon lift completion at
8 the well top.

9 It should be noted that other type of mechanical pickup
10 mechanisms could be designed to insure a 'positive'
11 mechanical contact during plunger lift.

12 Fig. 11 is a horizontal cross-sectional view of Fig. 2,
13 taken along line A-A, viewed in the direction taken by the
14 arrows. Shown is PBM 21 inside of inner diameter ID of well
15 tubing 9. If area A2 is equal to or greater than the minimum
16 cross-sectional area of any other flow point in the well,
17 full well flow can continue without the PBM impeding maximum
18 flow. PBM 21 has many different cross-sectional areas, and
19 although only one area is shown, if the 'difference' in any
20 cross-sectional area of the PBM and the inside cross-
21 sectional area of well tubing is equal to or greater than
22 the minimum cross-sectional area of any other flow point in
23 the well, full well flow can continue without the PBM
24 impeding maximum flow..

14 Fig. 12 is a horizontal cross-sectional view of Fig. 5,
15 taken along line B-B, viewed in the direction taken by the
16 arrows. PTM 20 is shown inside inner diameter ID of tubing
17 9. A very small gap G between the outside of PTM 20 and
18 inside diameter ID of tubing 9 allows PTM 20 to travel down
19 tubing 9 to the well bottom where it will attach to PBM 21.
20 In this case the inside cross-sectional area A1 of orifice
21 29 should be equal to or greater than the 'minimum' cross-
1 sectional area of any other flow point in the well in order
2 to optimize well flow.

3 Referring next to FIG. 13 the spring-loaded
4 topmechanism 510 is shown and described in FIG. 10.
5 However, a ball B serves as the sealing plunger, also called
6 the bottom mechanism.

7 Referring next to FIG. 14 the compression ring top
8 mechanism 1410 has an O ring, also called a compression ring
9 1411 in a groove 1411 of the lower arm 1412. This
10 embodiment functions similar to the FIG. 9 embodiment using
11 a ball B as the bottom mechanism.

12 Referring next to FIG. 15 the latch down top mechanism
13 310 is shown and described in FIG. 8. However, a ball B
14 serves as the bottom mechanism.

15 Referring next to FIG. 16 the top mechanism, also
16 called the sleeve 1600 has its lower segment 1601 shown in a
17 cutaway view to display magnets M which attract ball B.
18 Ball B serves as the bottom mechanism as in FIGS. 13, 14,
19 15.

1 Although the present invention has been described with
2 reference to preferred embodiments, numerous modifications
3 and variations can be made and still the result will come
4 within the scope of the invention. No limitation with
5 respect to the specific embodiments disclosed herein is
6 intended or should be inferred.

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